SOAH DOCKET NO. 473-00-1020
PUC DOCKET NO. 22355

APPLICATION OF RELIANT ENERGY, INC. FOR APPROVAL OF UNBUNDLED COST OF SERVICE RATE PURSUANT TO PURA § 39.201 AND PUBLIC UTILITY COMMISSION SUBSTANTIVE RULE 25.344	§ § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY AND EXHIBITS OF LEE SMITH

ON BEHALF OF

THE TEXAS RETAILERS ASSOCIATION
AND
THE TEXAS HOSPITAL ASSOCIATION

December 12, 2000

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Direct Testimony of Lee Smith

Part I. INTRODUCTION

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. WHAT IS YOUR OCCUPATIONAL EXPERIENCE?

A. I am a Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 16 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Exhibit LS-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Texas Retailers Association ("TRA") and the Texas Hospital Association ("THA"). The members of this group are retail customers of the HL&P and together are a significant stakeholder in the Texas electric industry restructuring proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying as to the revenue requirement claim put forth by Reliant Energy HL&P ("HL&P") in Docket No. 22355 to develop unbundled rates for the 2002 forecast year when competition opens in Texas.

Q. WHAT IS YOUR EXPERIENCE IN ELECTRIC INDUSTRY RESTRUCTURING?

A. I have assisted in rulemaking for a restructured industry and in drafting legislation in Massachusetts, and was a member of a number of several New England Power Pool ("NEPOOL") committees that created the New England Independent System Operator. I have addressed restructuring issues in Maine, New Hampshire, and Vermont. I contributed to testimony in New Jersey for the Division of the Ratepayer Advocate. I testified in eight cases in Pennsylvania on rate unbundling and retail market generation costs, and continue to advise the Office of the Consumer Advocate. In Maryland, I assisted the Office of the People's Advocate in electric restructuring cases. I advised the Ohio Consumer's Counsel on stranded costs and rate issues. I have testified in Arizona on stranded cost and retail restructuring for the Commission staff in numerous cases. In Arkansas I have been advising the Public Service Commission on various issues.

Q. WHAT IS YOUR EXPERIENCE IN ELECTRIC COST OF SERVICE ISSUES?

A. Since leaving the Massachusetts DPU, I have performed cost studies and prepared rate design for over twenty utilities in at least eleven states. I have developed cost of service studies and designed rates for a number of utilities. I have advised Commissions, consumer advocates, and other interested parties on cost of service, cost allocation, and rate design issues.

Q. HOW IS YOUR TESTIMONY ORGANIZED IN THIS PROCEEDING?

A. First I analyze the appropriateness of the costs related to shared services among various HL&P Corp. subsidiaries in its depiction of both historic costs and projected costs. Next I analyze various adjustments proposed by HL&P Electric to both distribution and transmission costs.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. I am recommending a number of discrete adjustments to the Company's request for increased rates. Specifically, I recommend disallowances to various areas of expense contained in Support Services, and to proposed capital additions to both distribution and transmission plant. Finally, I recommend rejection of the new depreciation study and calculate depreciation expense based upon my recommended rate base and the existing depreciation rates.

Part II – HL&P SUPPORT SERVICES COSTS

Q. PLEASE SUMMARIZE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. Here I address the reasonableness of certain support services costs included in the T&D Utility's cost of service for the 2002 forecast year. I begin by discussing the support services costs charged to HL&P in the historic test year by Reliant Energy, Inc.'s support services organization and by certain organizations embedded in HL&P during that year. I then address several proposed adjustments to those test year costs, most of which relate to the support services organizations embedded in HL&P. This is followed by a brief commentary on the approach used by the Company to escalate the adjusted test year costs to calendar year 2002 levels. My testimony will recommend that some of the proposed adjustments attributed to the T&D Utility in 2002 be disallowed.

Q. ARE YOUR RECOMMENDATIONS BASED ON A PARTICULAR TEXAS PUBLIC UTILITIES COMMISSION STATUTE?

A. Yes. My recommendations are based on Section 36.058 of the Public Utility Regulatory Act ("PURA"), which allows recovery of affiliate expenses but "only to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items."

Q. PLEASE BRIEFLY DESCRIBE THE ORGANIZATION AND PURPOSE OF RELIANT ENERGY, INC.'S CORPORATE SUPPORT SERVICES ORGANIZATION.

A. Reliant Energy conducts its business through a large number of subsidiaries and divisions. The various business units and executive management are supported by a number of functions, some of which were carried out at the Reliant Energy corporate level during the test year. The costs incurred in carrying out these functions are accumulated in corporate cost centers and recorded on the Reliant Energy Inc.'s general ledger. The organization of these functions is called Reliant Energy Corporate. Other support services were provided to Reliant Energy subsidiaries and divisions by organizations embedded in HL&P during the test year.

Q. WHAT TYPES OF SERVICES WERE PROVIDED BY RELIANT ENERGY CORPORATE DURING THE TEST YEAR?

A. The services provided by Reliant Energy Corporate to Reliant Energy, Inc and its business units during the historic test year include legal, finance, human resources, executive management, communications, regulatory and government affairs. These support services are provided at cost with no profit added, as required by Securities and Exchange Commission rule.

Q. WHAT TYPES OF SUPPORT SERVICES WERE PROVIDED BY HL&P ORGANIZATIONS DURING THE TEST YEAR?

A. The Information Technology ("IT"), Shared Services and Regulatory organizations resided in HL&P during the test year, as did most of human resources, which were provided by HL&P's Human Resources department. According to the Company's revised Business Separation Plan, in 2002 those organizations will become part of a corporate services subsidiary called REGCO, providing services to all affiliate companies.

Q. WHAT SERVICES ARE PROVIDED BY THE SHARED SERVICES ORGANIZATION?

A. Despite being part of HL&P during the test year, Shared Services provided Reliant Energy, Inc. and its subsidiaries the following services:

1. Facilities Management;
2. Financial Administration;
3. Office Support Services;
4. Procurement;
5. Corporate Security; and
6. Shared Services Administrative Support.

Q. WHAT TYPES OF SUPPORT SERVICES COSTS WERE INCURRED DURING THE TEST YEAR?

A. The expense categories include depreciation and amortization of equipment, maintenance of structures, salaries and wages, outside services, property insurance; injuries and damages; employee pensions and benefits; advertising and rents and leases. These expenses are either billed directly or assigned from a fixed and variable cost pool based on cost causation principles. The underlying IT assets were included in HL&P's rate base and depreciation and return recovered through regulated rates. Some of these costs would have then resulted in billings to and revenues from other affiliates for whom HL&P provided the services.

A. HISTORIC TEST YEAR AND 2002 FORECAST SUPPORT SERVICES COSTS

Q. WHAT WAS THE TOTAL COST OF SUPPORT SERVICES PROVIDED BY RELIANT ENERGY CORPORATE TO HL&P DURING THE HISTORIC TEST YEAR?

HL&P was billed $46.9 million during the test year, of which $22.3 million was attributable to the transmission and distribution operations.[1] As noted above, these amounts do not include the support services costs charged respectively to HL&P and its transmission and distribution operations by the IT, Shared Services, Regulatory and Human Resource organizations. These organizations were part of the integrated utility during the test year.

Q. HOW WAS THE 2002 FORECAST OF SUPPORT COSTS DEVELOPED AND WHAT IS THE AMOUNT?

A. The Company testifies that the 2002 forecast to support the T&D Utility was obtained by applying the Order No. 25 escalation rates to the "normalized" test year support costs assigned to HL&P's transmission and distribution operations, including those already embedded in those organizations, after adjusting for non-recurring costs and known service level changes. Because the Company does not provide this amount in one place, I have summed Company projections and derived a total of $120.91 million[2]

Q. WHAT WERE THE "NORMALIZED" OR ADJUSTED TEST YEAR AMOUNTS FOR HL&P AND THE T&D UTILITY?

A. The "normalized" test year cost for HL&P was $56 million and $26.6 million for the T&D Utility.[3] One adjustment was made to remove a 1998 refund from the test year

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[1] Figures MB-01and MB-04 to the Supplemental Direct Testimony of Marietta Blanton, November 17, 2000.
[2] Includes $41.18 million of normalized costs billed by Reliant Energy Corporate including Human Resources and Regulatory, $9.73 million by Shared Services, and $70 million by IT.
[3] See footnote 1.

numbers. This resulted in an increase to HL&P of $4.8 million and $2.3 million for the T&D Utility. A second adjustment was made to include in the test year numbers a true-up cost for the period December 1998 through August 1999 that was booked outside of the test year. This resulted in an increase to HL&P of $6.9 million, of which $3.3 million was attributable to the T&D Utility. Two other adjustments, one to remove the salary of the retired Reliant Energy, Inc. Chairman and another to correct a minor mis-allocation of support costs, were also made.[4]

Q. DO YOU SUPPORT THESE NORMALIZATION ADJUSTMENTS?

A. Because these adjustments only came to light in the Company's October 2, 2000 filing, I have had insufficient time to determine whether the adjustments are: (i) reasonable, (ii) functionalized appropriately, or (iii) escalated in accordance with the requirements of Order No. 25.

Q. YOU INDICATED THAT THE TEST YEAR COSTS ASSOCIATED WITH THE IT, SHARED SERVICES, REGULATORY AND HUMAN RESOURCE WERE ADDED TO THE HISTORIC TEST YEAR AMOUNT BILLED BY RELIANT ENERGY CORPORATE PRIOR TO COST ESCALATION. HOW DID YOU ADDRESS THESE COSTS?

A. The following five sub-sections summarize my concerns regarding the historic and forecast year costs for these four organizations and for HL&P's Public Affairs and Internal Communications organization.

1. <u>Human Resources</u>

Q. HAVE YOU BEEN ABLE TO ASCERTAIN THE DERIVATION OF PROJECTED HUMAN RESOURCE COSTS?

A. No. I do not find that historic and projected costs are appropriately related.

[4] Supplemental Direct Testimony of Marietta Blanton, pages 6-8.

Q. WHAT WAS THE HISTORIC TEST YEAR HUMAN RESOURCE COST ATTRIBUTABLE TO TRANSMISSION AND DISTRIBUTION OPERATIONS?

A. During the test year, HL&P transmission and distribution was assigned $6.2 million by Reliant Energy Corporate's Human Resources organization and $792,000 by the HL&P Human Resources organization that was established during the historic test year to support the Delivery Group.[5] The human resource total appears to be $6,992,000 for the test year. The Delivery Group includes the Reliant Energy operations that deliver energy to customers and comprises the local gas distribution businesses of Arkla, Entex, and Minnegasco and the transmission and distribution operations of HL&P. Mr. Hill does not indicate what part of HL&P provided support services to the entities in the Delivery Group prior to the establishment of the new organization.

Q. DID THE COMPANY USE THE ABOVE REFERENCED TEST YEAR COST AS THE BASIS OF ITS 2002 FORECAST OF HUMAN RESOURCE COSTS FOR THE T&D UTILITY?

A. No. Figure MB-07 to the Supplemental Direct Testimony of Ms. Blanton shows a total test year Human Resources cost of $10.95 million. This is $4.75 million more than the $6.2 million that Mr. Hill stated was assigned by Reliant Energy Corporate's Human Resources organization to HL&P's transmission and distribution operations, and $3.96 million more than the total of the Reliant assignment to T&D and the HL&P Delivery Group human resource costs.[6]

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING HUMAN RESOURCE COSTS?

A. It appears that Ms. Blanton has overstated test year human resource costs by almost $4 million. I recommend that T&D O&M should be reduced by $4 million, escalated at the

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[5] Supplemental Testimony of Norman Hill, November 17, 2000, page 2, lines 7-11.

[6] Note that Ms. Blanton appears to attribute the $6.2 million cost to the Human Resources organization that resided in HL&P during the test year. Supplemental Direct Testimony at page 6, lines 5-11.

average rate utilized by Ms. Blanton. I have then divided this adjustment between distribution and transmission based on total O&M, resulting in a reduction of $1.1 million for transmission and $2.9 million for distribution.

2. <u>Regulatory</u>

Q. WHAT ARE THE REGULATORY EXPENSES ATTRIBUTABLE TO TRANSMISSION AND DISTRIBUTION DURING THE TEST YEAR?

A. Despite providing services to other regulated affiliates, the Regulatory organization was part of HL&P during the test year.[7] According to a data response sponsored by Ms. Blanton, out of a total test year cost of approximately $7 million,[8] the transmission and distribution operations of HL&P were assigned $5 million.[9] However, Mr. Roesler's Supplemental Testimony appears to defend a T&D Regulatory expense of $5.2 million.

Q. DOES THAT ASSIGNMENT SEEM REASONABLE?

A. No. Mr. Roesler in his Supplemental Testimony supports $5.2 million of regulatory service costs to the T&D.[10] Those full $7 million of regulatory services enabled HL&P to fulfill various commitments, including representing its interests in rate and tariff proceedings and rulemakings before regulatory authorities. The allocation to generation, based on my experience and standard allocators, is low.

Q. WHAT WOULD BE AN APPROPRIATE ALLOCATION OF TEST YEAR REGULATORY COSTS TO GENERATION?

A. According to the Company, the employees of the Regulatory organization devote more of their time to the largest businesses because those businesses tend to generate the greatest earnings. Based on this rationale, the Company proceeded to assigned regulatory costs to

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[7] On January 1, 2000, Regulatory became a part of Reliant Energy Corporate.
[8] Response to TRA 22-30.
[9] Figure MB-07, Supplemental Direct Testimony of Marietta Blanton, November 17, 2000
[10] Supplemental Testimony of Wayne Roesler, page 1.

business units based on assets.[11] Consistent with that approach, I functionalized the $7 million assigned to HL&P based on net plant in service. This resulted in an increase to generation of $1.9 million and reduced the amount assigned to the transmission and distribution operations by the same amount.

3. **Shared Services**

Q. WHAT ARE THE SHARED SERVICES EXPENSES ATTRIBUTABLE TO HL&P DURING THE TEST YEAR?

A. Out of a total test year cost of $64 million, HL&P was assigned $56 million and other affiliates the remaining $8 million.[12]

Q. WHAT PORTION OF THE $56 MILLION TEST YEAR COST WAS ATTRIBUTABLE TO THE TRANSMISSION AND DISTRIBUTION OPERATIONS?

A. According to the Company, this information is not available because the Shared Services organization was part of the integrated utility during the test year.[13] Instead, Mr. Schoeneberg estimated the amount at $9.1 million based on the calendar year 2000 budget for the Shared Services organization rather than on test year costs. Specifically, Mr. Schoenberg reduced the calendar year 2000 budget amount of $32.8 million by $23.7 million to account for expected reductions in service requirements due in part to the decision to leave certain Shared Services employees with the T&D Utility and the direct billing of third party costs to the T&D Utility (i.e., the salaries of these employees are reflected in T&D Utility O&M).[14] In other words, the estimated test year Shared Services cost attributable to HL&P's transmission and distribution operations are in fact the result of adjustments to calendar year budget 2000 costs to eliminate services that the

[11] Response to Hou 7-10.
[12] Direct Testimony of Allen Schoeneberg, March 31, 2000, page 2, lines 19-21.
[13] Response to Hou 7-3.
[14] Response to Hou 7-5 and 7-6.

T&D Utility will no longer require.[15] Because the $9.1 million is not based on historic test year costs, it should be disallowed in its entirety or reduced by a percentage to reflect the Company's failure to respond to Order No. 25 and the ALJ's rulings at the prehearing conference held November 10, 2000.

4. **Information Technology**

Q. IS THE COMPANY REQUESTING ADJUSTMENTS RELATIVE TO IT SERVICES?

A. Yes. The Company is making major changes to the way it provides Information Technology ("IT") services. In the test year IT plant was owned by the utility and its costs consisted of return and depreciation on rate base. This plant will be transferred to a support services affiliate, which will then bill IT to the distribution utility.

Q. WHAT PORTION OF THE COSTS INCURRED BY HL&P'S IT ORGANIZATION DURING THE HISTORIC TEST YEAR WAS BILLED TO TRANSMISSION AND DISTRIBUTION OPERATIONS?

A. During the historic test year, HL&P billed itself $65.2 million for IT services, excluding the return of and on depreciable IT equipment.[16] This is approximately 55% of the total test year IT expense of $119.2 million.[17] The HL&P amount attributable to transmission and distribution was approximately $36.1 million.[18] After cost escalation, and the addition of $3.7 million of SB 7 related costs and $27.7 million of depreciation and return related to IT equipment currently in HL&P's rate base, the Company claims a total cost of $70 million in 2002 attributable to transmission and distribution.[19]

Q. DOES THE $36.1 MILLION TEST YEAR COST ATTRIBUTED TO

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[15] Response to Hou 7-5.
[16] Direct Testimony of Ianthe McCrea, March 31, 2000, page 6.
[17] Figure IHM-S1 to Supplemental Testimony of Ianthe McCrea, November 17, 2000, page 5.
[18] Ibid. Excludes Bill Print costs.
[19] Supplemental Testimony of Ianthe McCrea, page 2.

TRANSMISSION AND DISTRIBUTION INCLUDE IT'S SHARE OF THE $5.9 MILLION BILLED TO HL&P'S REGIONAL OPERATIONS GROUP BY IT AND SHARED SERVICES?[20]

A. That is not clear. Neither the test year costs for the IT organization as shown in Figure IHM-S1 to Ms. McCrea's Supplemental Testimony or for the Shared Services organization as shown in Figure AES-7 to Mr. Schoenberg's Testimony separately identify support costs for HL&P's Regional Operations organization. Thus, there is a question as to whether the $5.9 million is included in the category labeled HL&P Division (T&D operations) or in the other O&M expenses addressed in the Supplemental Testimony of Mr. Brian or in both. Because this uncertainty creates the possibility of costs being recovered twice (including the associated escalation), the Commission should require the Company to clarify its handling of this cost prior to approving the recovery of any IT support services costs.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S $70 MILLION IT BUDGET FOR THE T&D UTILITY?

A. Yes, I have concerns in several areas. First, as with the Shared Services costs attributed to transmission and distribution, there appears to be little support for the historic $36.1 million attributed to transmission and distribution operations.[21] The Company responded to several interrogatories requesting data on test year costs claiming that such data was unavailable because the IT organization was part of the integrated utility at that time. Second, the Company has not justified the addition of $3.7 million for the maintenance of a so-called "multiple client environment" to its customer information system. My experience with the restructuring of electric utilities around the country leads me to believe that restructured transmission and distribution companies can communicate adequately with REPs, using electronic data interchange ("EDI") systems, and secure confidential customer and REP data without incurring the level of expense included in

[20] Direct Testimony of Georgianna Nichols, page 19-20.
[21] Including the allocation of HL&P assigned IT costs to generation and non-generation businesses and the subsequent allocation of the costs to the regulated and non-regulated functions.

the Company's filing. This issue is addressed later in my testimony.

Q. WHAT ARE YOUR OTHER CONCERNS?

A. In her original testimony, Ms. McCrea claimed that the annual fee required to recover costs previously recovered through regulated rates was $18 million for the T&D Utility in 2002.[22] In her October 2 filing, this fee increased to $27.7 million.[23] The difference, according to Ms. McCrea, is that the $18 million was incorrectly calculated and reflected the end of test year net book value of the IT equipment instead of year end 2001.[24] The Commission should reject this increase because the use of year end 2001 equipment balance to calculate a portion of the support services costs is contrary to the Commission's decision in Order No. 25 that support services costs be based on historic test year amounts. This 2002 IT expense resulting from only an organization change should be calculated based on of depreciation expense and return on investment on December 31, 1999 plant balances, escalated using the Commission approved generic escalation rates. Further, if the Company is claiming that the approximate $9.7 million difference between its initial and its revised filing is due to capital additions, no evidence has been provided to support these capital additions.

In addition, the Commission should disallow the Company's request to recover the combined IT and Shared Services administrative support cost attributed to transmission and distribution. This cost is included in the administrative support charges provided in Figure AES-5 to Mr. Schoenberg's Direct Testimony because IT was part of the Shared Services organization during the historic test year and only became a separate organization in late 1999. In calendar year 2000, this cost was estimated at $1.7 million.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION TO DISALLOW ADMINISTRATIVE SUPPORT COSTS?

[22] Direct Testimony of Ianthe McCrea, March 31, 2000, page 20.
[23] Supplemental Testimony of Ianthe McCrea, November 17, 2000, page 6.
[24] Ibid.

A. There are two reasons. First, the $1.7 million amount is a calendar year 2000 figure. The test year amount was not provided. Second, the Company provided no justification for the continued recovery of this cost after both organizations become part of a much larger and presumably more efficient Reliant Energy Corporate organization.

Q. DO YOU HAVE CONCERNS REGARDING THE REASONABLENESS OF THE IT COSTS THAT THE COMPANY IS SEEKING TO INCLUDE IN ITS 2002 FORECAST REVENUE REQUIREMENT?

A. Yes. Ms. McCrea uses a benchmarking study performed by the Gartner-Group to support the reasonableness of HL&P's IT costs. This study does not compare HL&P's historic test year IT costs to the IT costs of comparable utilities but instead uses 2000 budget data for that purpose. Because the Gartner-Group study is not based on historic test year data, the conclusions drawn from that study cannot be applied to the test year costs. As a result, the Company has failed to support the reasonableness of its test year IT costs and hence its 2002 forecast costs.

Q. WHAT IS YOUR TOTAL RECOMMENDED DISALLOWANCE OF TEST YEAR SUPPORT SERVICES COSTS FOR THE T&D UTILITY?

A. My total disallowance is $26.4 million. The equivalent 2002 amount is $28.5 million using Ms. Blanton's average escalation rate.

Q. WERE YOU ABLE TO CONFIRM THAT THE COMPANY COMPLIED WITH ORDER NO. 25 AND ESCALATED THE HISTORIC TEST YEAR SUPPORT SERVICES COSTS BILLED TO THE REGULATED FUNCTIONS USING THE COMMISSION APPROVED GENERIC ESCALATION RATES?

No. According to the Supplemental Testimony of Mr. Brian, the historic test year support services costs assigned to HL&P's regulated functions were bundled with other test year O&M expenses and the total escalated using the generic factors. As a result, the escalation adjustment for the support services portion of O&M expense was not separately identified in the Company's filing.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE 2002 FORECAST OF SUPPORT SERVICES COSTS FOR THE T&D UTILITY?

A. Given the Company's failure to provide a separate escalation analysis for support services costs, and the requirements set forth in PUR 36.058, I recommend that the Commission condition recovery of the escalation component of support services cost on the Company providing detailed support for its O&M escalation analysis. Specifically, the Company should fully unbundle its test year O&M expense, identify the support services components, and support the escalation factor applied to each component.

5. <u>Public Affairs</u>

Q. WAS THE PUBLIC AFFAIRS AND INTERNAL COMMUNICATION ("PUBLIC AFFAIRS") ORGANIZATION PART OF RELIANT ENERGY CORPORATE DURING THE HISTORIC TEST YEAR?

A. No. Public Affairs was part of HL&P during the historic test year but will move to REGCO Corporate in 2002, where it will provide services to HL&P and Reliant Energy Entex. Although the Company did not include the 2002 budget for this organization in its 2002 corporate support services forecast, I address Public Affairs support costs in this part of my testimony because of the similarities between this organization and others discussed above.

Q. WHAT SERVICES WERE PROVIDED BY THE PUBLIC AFFAIRS ORGANIZATION DURING THE HISTORIC TEST YEAR AND WHERE WAS THAT ORGANIZATION LOCATED?

A. During the test year, the Public Affairs organization purpose was to: (i) communicate information to customers of HL&P and Entex on a range of issues; (ii) educate and motivate employees of both organizations so as to promote greater efficiency; and (iii) work with the media to ensure an accurate depiction of Company policy and goals.

Q. WHAT WERE THE TEST YEAR EXPENSES ATTRIBUTABLE TO TRANSMISSION AND DISTRIBUTION AND WHAT IS THE FORECAST FOR THE YEAR 2002?

A. Billings to HL&P from the Public Affairs organization were $5.4 million during the test year. The 2002 forecast for the T&D Utility is projected to be $3.7 million.[25] According to the Company, the decrease is the result of a reduced advertising budget related to business separation.[26]

Q. WHAT ARE YOUR CONCERNS REGARDING THE 2002 FORECAST?

A. I have three concerns. The first relates to the functionalization of the historic test year cost of $5.4 million incurred by HL&P. Mr. Painter, the Vice President of Public Affairs, describes the Public Affairs organization in his testimony as being part of the integrated utility and in discovery as part of the transmission and distribution division.[27] The distinction is important because it has a bearing on the functional allocation of the Public Affairs test year cost, and hence on the 2002 forecast for the T&D Utility. If, for example, the organization provided services that benefited only employees and customers of the T&D division of HL&P, then it may be appropriate to allocate all test year costs to that division. If, however, those services also benefited generation employees and customers, then it would be appropriate to allocate a portion of the test year cost to the generation function. Given the purpose of the Public Affairs organization and the fact that the customers of an integrated utility are by definition customers of the T&D and generation operation, it would appear logical to allocate the test year costs to all functions.

Q. PLEASE CONTINUE.

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[25] Response to TRA 22-35.
[26] Advertising costs accounted for almost three fifths of total year costs. See response to TRA 22-35 and 37.
[27] Supplemental Testimony of Graham Painter, page 1, lines 21-22.

As noted above, Public Affairs comprises customer communication, employee communication and advertising. Customer communications costs include monthly bill insert printing, printing brochures on efficient energy use, designing and maintaining the HL&P Internet site, and designing and printing hurricane-tracking charts. Employee communications costs include printing monthly newsletters and other employee informational pieces, maintaining an intranet site, and printing company goals and reports. Advertising costs cover print, radio, and television ad production and placement. These services and the associated costs would appear to benefit all aspects of the integrated company and should therefore be shared among all functions including generation.

Q. WHAT ACTION DO YOU RECOMMEND REGARDING THE PROPOSED PUBLIC AFFAIRS BUDGET?

A. The Commission should reduce the T&D test year expense from Public Affairs by $1.8 million, as a result of allocating a portion of the $5.4 million test year cost to the generation function after removing the costs of services no longer required by the T&D Utility. The equivalent 2002 amount is $1.9 million. This allocation is based on the percentage of generation-related net plant in service to total net plant in service at December 31, 1999. Second, the Commission should condition the continued recovery through regulated rates of advertising costs on a showing that the costs are necessary for the safe and reliable operation of transmission and distribution facilities.

Part III – CLAIMED INCREASES IN DISTRIBUTION COSTS

Q. WHAT IS THE PURPOSE OF THIS AND THE NEXT TWO PARTS OF YOUR TESTIMONY?

A. Herein I analyze and suggest modifications to the Company's adjustment to its "historic" booked costs of distribution. Part IV does the same for the transmission cost of service. Part V criticizes the Company's requested increase in depreciation rate and expense.

Q. DOES THE COMPANY CLAIM THAT THERE WILL BE A LARGE INCREASE IN T&D COSTS AS A RESULT OF MOVING TO RETAIL ACCESS?

A. Yes. In its original filing request, the increase was summarized in the response to TRA10-5. This shows an increase in non-bypassable T&D costs from 1.2 to 2.1 cents per kwh, or from $502 to $817 per average customer. This increase appears to be primarily driven by capital costs, since the T&D charge per employee increases 62%, very little of which can be salary related. The revised filing of November 17 requests an increase in distribution cost of service increase of 34%, without depreciation expense, which reflects a redirection of expense from generation. In part II I discussed the Company's "historic year" and its projected year support costs, including IT expense. Below I discuss my concerns with the increase in capital costs.

Q. HOW LARGE ARE PROPOSED DISTRIBUTION PLANT CAPITAL ADDITIONS?

A. The Company projects distribution plant additions that are 32% of the original book value of distribution plant for the historic year, or $983 million, in spite of the fact that the IT plant is moving out of regulated rate base.

Q. HAS THE COMPANY JUSTIFIED ITS PROJECTED INCREASE IN DISTRIBUTION PLANT?

A. No. Mr. Brian testifies that the Company is adopting sophisticated enterprise-wide software solutions which hold the prospect of gains in productivity and efficiency. (p. 46 testimony). These systems include a SAP project, general plant, and communications plant in service (CPIS). The Company has not reflected any decreases in expense associated with these plant additions, nor has it established that these are necessary.

Q. DOESN'T RESTRUCTURING REQUIRE CERTAIN CHANGES IN THE WAY THAT THE COMPANY DOES BUSINESS?

A. Yes. However, most of these changes are incremental in nature. Moreover some of the "new systems" are likely to provide additional benefits to the Company, perhaps even incremental sources of revenue. The gains in productivity and efficiency anticipated by Mr. Brian will reduce costs. This cost reduction has not been reflected in the Company's projected 2002 costs. Moreover, most of the Company's proposed additions are directly related to the restructuring of the electric industry.

Q. HOW DOES THE COMPANY CATEGORIZE ITS PROPOSED DISTRIBUTION CAPITAL ADDITIONS?

A. The Company categorizes its proposed capital additions into customer growth, maintenance & reliability, service restoration, and capital operations & support expenditures.

Q. PLEASE DETAIL YOUR CRITICISMS OF THE COMPANY'S CUSTOMER GROWTH EXPENDITURES.

A. In the test year the Company spent $67.2 million or, on average, $2800 per housing start (based on 23,949 starts). Ms Nichols, on page 32 of her testimony, states that housing starts were projected to be in the 23,000 to 24,000 range, yet the Company is projecting to spend $76 million, or $3234 on average, based on 23,500 starts. That is an increase in capital cost of 15% per unit. The Company has given no justification as to the reason behind the increase in the per unit cost of new customer installations.

Q. HAS THE COMPANY JUSTIFIED ITS FORECAST OF EXPENDITURES RELATED TO THE RELOCATION OF EXISTING PLANT?

A. No. In her testimony on page 33, Ms. Nichols states that the Company spent $8.7 million on plant relocations in 1999 and is expected to spend $14.9 million in 2000. No reason for the increase in cost is given in Ms. Nichols' testimony. Ms. Nichols explains these expenditures are the result of new communities being developed. As I mentioned earlier, the Company is projecting roughly the same level of development in 2000 as in 1999, as measured by housing starts, yet it is projecting a 71% increase in the rate of investment for a development driven cost. Furthermore Ms. Nichols makes no mention, in either her testimony or workpapers, of customer contributions in aid of construction offsetting a portion of the cost of relocating distribution plant.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CAPITAL EXPENDITURES FOR CUSTOMER GROWTH?

A. Based on the Company's own projections of the rate of development in the forecast period I recommend capital expenditures for customer growth should be at the test year level of $67 million for 2000, 2001, and 2002. Similarly the expenditures for relocation of existing plant, should be based on the 1999 level of investment, or $8.7 million for 2000, 2001, and 2002. This is a reduction of $56.4 million to the Company request.

Q. HAVE YOU REVIEWED THE COMPANY'S FORECAST OF CAPITAL EXPENDITURES FOR MAINTENANCE AND RELIABILITY?

A. Yes.

Q. DO YOU HAVE ANY OBJECTIONS TO THE COMPANY'S FORECAST?

A. Yes. Ms. Nichols states that the Company is planning to expand the "rotten pole program" to replace all poles starting in 2001 at an annual incremental cost of $4.5 million. The Company justifies this program as necessary to meet the new SB7 reliability requirements. I recommend that the Commission disallow the entire $4.5 million in each year. The Company has not proven that the SB7 reliability standards are not attainable with the existing poles. Furthermore, replacing poles some of which may have been replaced 5 to 10 years ago will not improve reliability as there should be very little if any damage to those poles. Replacing all poles regardless of age or amount of rot is an imprudent and wasteful expense to ratepayers.

Q. WHAT DOES THE COMPANY REQUEST FOR SERVICE RESTORATION CAPITAL EXPENDITURES AND WHY?

A. These expenditures are for replacement of overhead, underground, and streetlighting equipment that is damaged. The Company projects that its annual capital additions will increase by about 70%, and remain at this level over the next three years. According to Ms. Nichols' March 31 testimony (p.37), the primary reason for the increase is a change in capitalization treatment. Previously, transformers were capitalized upon purchase, and starting in 2000 they will be capitalized upon installation in a different budget location.

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S PLANS FOR SERVICE RESTORATION EXPENDITURES?

A. I recommend the Commission disallow any increase in service restoration expenditures over the test year. The Company has not demonstrated that a difference in timing of capitalization and of the organization in which the cost is accounted results in a higher cost. The only possible increase in expenditures will be from the installation labor that will be capitalized instead of expensed. Moreover, transformers are only a portion of the capital expense in this category, and the Company has not justified that a small change of accounting treatment in only one portion of this expenditure should lead to such a significant change in overall capital expenditures for this category.

Q. HAVE YOU EXAMINED THE COMPANY'S FORECAST OF INVESTMENT IN CAPITAL OPERATIONS AND SUPPORT ACTIVITIES?

A. Yes.

Q. HAS THE COMPANY PROVEN THE INCREASES IN INVESTMENT IN DISTRIBUTION SUPPORT TO BE NECESSARY AND REASONABLE?

A. No. The Company plans to increase investment in support activities by 74% from 1999 to 2002 yet the Company's forecast of expenses related to support activities declines by about 1%. The Company has not justified thc proposed level of investment in support activities. There does not appear to be any evidence that the current level of capital additions is not adequate to provide the distribution support organization the assets it needs to effectively service the distribution organization. I recommend that investment in operations and support activities be based on the 1999 level.

Q. ASIDE FROM YOUR SPECIFIC CRITICISMS OF THESE INCREASES IN CAPITAL COSTS, DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THE APPROPRIATENESS OF THE PROPOSED INCREASES IN DISTRIBUTION RATES?

A. Yes. Across the county, I am aware of at least 26 utilities that have introduced competition and continued to operate successfully without increases in rates. Most of these utilities continue to have full responsibility for customer billing and providing generation service to some customers. These utilities have managed to adjust billing, communicate with alternative suppliers, and provide a multitude of other services that allow retail access to work, without rate increases. In Massachusetts, all utilities were required to provide retail access with not only no increase but with a decrease in their total rates. In New Hampshire, the same was true for Public Service Company of New Hampshire and Granite State Electric. In Pennsylvania all utilities are providing retail access and all of their distribution rates have been frozen for 4 or more years. In Maryland, utilities have provided retail access with no distribution rate increase. In Arizona, Arizona Public Service and Tucson Electric Power Company have decreased their distribution rates while providing retail access. This leads to the conclusion that either all of these utilities were previously over earning, and thus could afford to institute new systems, or the net cost (less revenues) of those systems was not very expensive, or that the companies have been able to institute efficiencies that compensate for any new costs.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATIONS REGARDING DISTRIBUTION RATE BASE?

A. Distribution original plant value in rate base should decrease by $109.4 million from the Company's requested increase of $982.6 million (original plant from Sched.III-B-1 less original plant from Sched. II-B-1). This decreases the allowed distribution return by $10.3 million, even using the Company's requested rate of return. My total adjustments to distribution cost of service are shown in Exhibit LS-2.

Part IV – CLAIMED INCREASE IN TRANSMISSION COST

Q. HOW MUCH OF AN INCREASE IN TRANSMISSION REVENUES IS THE COMPANY REQUESTING IN ITS REVISED FILING?

A. The Company claims that its transmission cost of service will increase 53% over its historic transmission cost of service, excluding the redirection of depreciation.

Q. HOW HAS THE COMPANY ESCALATED HISTORIC TRANSMISSION O&M?

A. The Company's revised filing escalates historic year expenses by the escalators specified in Order 25.

Q. DOES THE COMPANY PROJECT AN INCREASE IN TRANSMISSION RATE BASE?

A. Yes, the Company forecasts capital additions of $486 million, or 37% of the original transmission plant cost.

Q. TO WHAT DOES THE COMPANY ATTRIBUTE THE INCREASE IN TRANSMISSION PLANT?

A. Mr. Houston testifies that the major cause of this transmission investment is interconnection of merchant generating plants. This gives rise to approximately $300 million of increased investment. He includes in this category not only investment that is necessary to connect new generators but also transmission lines to deliver additional power. These latter investments might also be described as congestion relief projects. Other causes of transmission investment listed by Mr. Houston are area load growth, and routine replacements, relocations, and service extensions.

Q. THE COMPANY DESCRIBED ALL OF THIS PROJECTED TRANSMISSION INVESTMENT RELATED TO NEW MERCHANT PLANTS AS NECESSARY TO THE FUNCTIONING OF THE COMPETITIVE MARKET? DO YOU AGREE WITH THIS CHARACTERIZATION?

A. No. They are actually arguing both that all of this investment is necessary and that it will all be used and useful by the end of 2002, which is the justification for putting this unbuilt plant in rate base. I do not think they have fully established the first point, and they have certainly not proven the second point.

Q. PLEASE EXPLAIN WHY YOU ARGUE THAT THE COMPANY HAS NOT DEMONSTRATED THAT ALL THIS TRANSMISSION INVESTMENT WILL BE NECESSARY BEFORE 2003.

A. There are several steps to this issue. First is the construction of new capacity, second is the connection of that capacity, and third is the wheeling of the power from that new capacity to load. New generators require connection to the transmission grid. They may or may not require enhancement of the bulk transmission system. However, the new generators in question are built to supply the competitive market. The more generators that are built, the more downward pressure there will be on competitive price. This will make building new generators less profitable and eventually unprofitable. It is basic to the competitive market that private entities compete to provide the product, and some of these entities will not succeed. In the electric generation context, this means that high demand and rising prices cause many entities to plan to build generating plants. It would be very surprising if the amount of projects proposed at any particular time resulted in the equilibrium amount of capacity. If the amount of capacity proposed is greater than the equilibrium, some of the projects will be cancelled and others will be delayed. The obvious implications for interconnecting the plants is that it is unlikely that all of the proposed plants will be built, which will mean that the some of the proposed interconnection investment will not come to fruition.

The Company projects that 6000 MWs of new generation will be constructed by 2002. It is my understanding that this amount of generation is roughly enough to meet ERCOT's entire peak growth from 2000 to 2002. Other Texas utilities report that significant amounts of new generation are being built in their service territories. Even allowing for the fact that some of this generation will displace production by older units, it appears that more generation is being planned than will be economic. The three major utilities, TXU, CP&L, and Reliant together project that 22,000 MWs of new generation to be built in the near term. This would meet the growth in ERCOT peak and replace some 16,000 MWs of existing capacity. In addition, Reliant believes that there will be significant self-generation in its territory. This may be similar to New England where only a fraction of the projects planned two years ago are built or even still "in the pipeline."

The next question is whether all of the projected plant will be necessary and whether it will be completed and providing service in the year 2002.

Q. THE COMPANY TESTIFIES THAT ALL OF THIS PLANT WILL BE NECESSARY. WHAT IS YOUR BASIS FOR DISPUTING THAT CLAIM?

A. First, new generation plants will in some cases make transmission investment unnecessary or less necessary. For instance, if there was a transmission bottleneck that meant that economic energy could not be transported to region A, the congestion could be relieved by transmission construction or by building generation in region A, so that it did not have to move across the bottleneck. Given the amount of uncertainty about both loads and new generation, it is difficult if not impossible to project several years in advance the solution to such a problem. A new generator could be proposed next month in a location that would obviate the need for a particular currently planned transmission enhancement. For instance, Mr. Houston speculates that subsequent plants will exacerbate loading problems to the corridor to the west of the King substation (Houston

p. 39). If one or several of these plants commit long-term to providing power to customers to the east, this may alleviate rather than exacerbate these problems.

Mr. Houston testifies that the base case transmission studies do not include potential new generators which are still in the planning stages or are confidential. (Houston p. 15 lines 13-15) It is clear from his description of the transmission planning process that it is extremely dynamic and necessarily imprecise as it moves farther into the future. In six months from now the best solution for the year 2002 may appear quite different from the best theoretical solution estimated six months ago.

In addition, the definition of "need" here is imprecise. It is not being claimed that the lights will go out if all of these transmission investments are not made. Rather, a generator located in region B may not be able to move power to region C at all hours because the existing transmission system is fully utilized during certain hours. This is a basic characteristic of all transmission systems. Sometimes the most economic solution is to build transmission, sometimes the most economic solution is to build generation, and sometimes the most economic solution is to live with the congestion. The Company has not established that all of its projected investment will be the most economic solution. It is also possible that some of the projected transmission investment will be the most economic solution but not until years after 2002. The Company's Design Criteria for transmission do not make it clear what level of congestion is considered acceptable (Figure JCH-2), but the fact that ERCOT Transmission protocols refer to redispatch of generating units strongly implies that some level of congestion is to be expected and allowed. (Redispatch occurs then there is congestion on a transmission corridor that prevents some generator from flowing during some hours.)

Q. DO YOU THINK THAT NONE OF THE GENERATOR INTERCONNECTION OR CONGESTION REDUCTION PROJECTS SHOULD BE ALLOWED IN RATE BASE AT THIS TIME?

A. No, but I strongly recommend that the requested increase in rate base be reduced. If it is the Commission's intent to allow a future rate base, then plant that we are fairly certain will be completed and be used and useful should be recognized in rate base. However, circumstances argue for a very conservative allowance. There is no realistic way to reduce rates if the amount of actual transmission investment is less than the amount allowed in rates, while the Company does have the ability to request subsequent increases in transmission rates if actual investment is greater than that allowed. This conservative approach also seems appropriate as an offset to using an end of year rate base, since customers at the beginning of the year will be paying for plant that is not yet in use.

Q. HAS HL&P PERFORMED RIGOROUS ANALYSIS OF WHICH PROJECTS ARE ACTUALLY LIKELY TO BE COMPLETED?

A. The Company has not provided any analyses which compares the rate of generation project proposals to project completions. Mr. Houston argues that new generators for which interconnection studies are being undertaken have made a strong commitment to build, "...as demonstrated by funding an interconnection study and in the resource commitments involved with working with our personnel on the plant interconnection." (Houston p.30) He also testifies that these studies cost at least $10,000. Given that a new generating unit of 1000 MWs will probably cost about $500 million in total, the expense of $10,000, or even double that amount, will not commit the developer to a unit that turns out to not be economic.

Q. WHILE THE COMPANY MAY NOT HAVE DEMONSTRATED THE REASONABLENESS OF THESE PROJECTS, IS THERE ANY FACTUAL INFORMATION THAT MAY ALSO CAUSE YOU TO DOUBT THAT THESE DOLLARS SHOULD OR WILL BE SPENT IN THE NEXT THREE YEARS?

A. In addition to the fact that there is no evidence that all of the projected transmission investment will be completed or has even begun, when we look at recent actual experience it does not support the projected rate of increase in transmission plant. The Company here is claiming that it will spend an average of five times that amount annually over the next three years. We must question where all the transmission engineers and construction workers will come from that will allow this rate of investment.

Q. WHAT DO YOU RECOMMEND BE ALLOWED AS AN INCREASE TO TRANSMISSION RATE BASE?

A. I recommend that the Commission assume that one third of this projected investment is either cancelled or not completed before the end of 2002. This requires a negative adjustment to HL&P's transmission rate base of $ 137 million. The total transmission cost of service adjustments are shown on Exhibit LS-2

PART V. DEPRECIATION STUDY

Q. THE COMPANY IS PROPOSING TO CHANGE ITS DEPRECIATION RATES. WHAT IS THE MAJOR CHANGE IN THE PROPOSED RATES?

A. Most distribution depreciation rates increase substantially, while there is little change in transmission, general and transportation depreciation rates.

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY.

A. Mr. William Stout prepared a depreciation study based on Company plant accounting entries from 1974 to 1998. This study uses two different methods to determine expected remaining life for most accounts, depending on whether the Company has vintaged data on retirements or not. For plant accounts with vintaged information, the depreciation rate and other information were based on historical data using the retirement rate method. However, this data was adjusted in various ways and standard Iowa survivor curves were also utilized. For plant accounts without vintaged data, Mr. Stout simulated plant balances on the basis of standard survivor curves. Depreciation rates have increased for every account (RFI HOU 3-10).

Q. WHAT APPEARS TO BE THE CAUSE OF THIS INCREASE?

A. The net salvage rates computed by Mr. Stout have decreased dramatically enough to cause an increase in depreciation rates even for accounts where average life has been increased. While plant lives for transmission have increased, for most distribution and general plant accounts expected lives have also decreased.

Q. **HAVE YOU COMPARED THE RESULTS TO THE COMPANY'S PREVIOUS STUDY?**

A. Yes. Exhibit LS-3 is a summary of the present lives and net salvage percentages from Request No. HOU 3-10. For most categories of distribution and general plant, Mr. Stout's study has decreased both the expected lives and the net salvage percentages.

Q. **HOW WERE THE SALVAGE RATES CALCULATED?**

A. Mr. Stout examined salvage and removal costs by plant account from 1974 to 1999. These are computed as percentages of the original book value of plant retired in each year. Net salvage rates were also grouped into three-year, and five-year moving averages. Most net salvage rates for distribution and transmission plant accounts selected by Mr. Stout for use in calculating the depreciation rate were negative.

Q. **WHAT DO YOU MEAN THAT "MR. STOUT SELECTED A RATE?"**

A. Mr. Stout testifies that the salvage estimates "were based on judgment" which incorporate historic data and expectations about future levels of removal and salvage costs.

Q. **WHAT IS A NET SALVAGE RATE, AND HOW CAN IT BE NEGATIVE?**

A. The net salvage rate is developed by adding salvage values from retired plant, which is usually positive, to removal cost, which is normally negative. The net salvage amount will be added to the original value of plant to determine how much the Company must collect through depreciation to reflect the full cost of the utility plant. Thus if retiring plant brings in value, the Company needs to collect less than the original value of plant, but if the net salvage value is negative, the collection through depreciation may be greater than the original value of plant. The depreciation rate is calculated as the net book value of surviving plant, plus net salvage, divided by remaining years of life, divided by original book value.

Q. WHY DO YOU RECOMMEND REJECTING THE TRANSMISSION AND DISTRIBUTION SALVAGE RATES USED BY MR. STOUT?

A. Mr. Stout's judgments regarding net salvage rates appear to consistently result in choosing the alternative that would produce higher depreciation rates. These net salvage rates are much lower than the net salvage rates reported by most utilities. The period of study is narrow, and ends in a year in which scrap metal prices were quite low. Mr. Stout does not appear to have investigated what may have caused net salvage rates to decrease, and whether this trend may reverse itself.

Q. ARE THERE HYPOTHESES THAT MIGHT EXPLAIN A CHANGE IN NET SALVAGE RATES?

A. Yes. As I already mentioned, scrap metal prices now appear to be increasing, which will increase salvage value. Technological change, such as improved bucket trucks, may cause removal costs to decrease. Removal costs may decrease because as newer plant is retired it may contain less hazardous materials. For instance, the Company is probably now retiring some transformers that were made after PCBs were banned, and are thus less expensive to remove. The proportion of these newer transformers in the retirement account will increase every year.

Q. PLEASE INDICATE WHY YOU SAY SOME OBSERVATIONS WERE EXTRAORDINARY?

A. For account 367, Underground Conductors and Devices, the 1998 observation was anomalous. The previous net salvage rate was a positive 8 percent, but Mr. Stout defined the rate as a negative 15%, Account 367 in 1998 experienced a removal cost that was extraordinarily high, a percentage of 33%, compared to the historic average of 20%. If this single observation were removed, the data would not appear to justify a net salvage rate below 11%. (Figure WMS-1 III-92)

Q. ARE THERE OTHER INDICATIONS THAT MR. STOUT'S JUDGMENT APPEARS TO ALWAYS HAVE INCREASED DEPRECIATION RATES?

A. Mr. Stout does not appear to have selected net salvage rates from the sets of three observations (i.e. observation period average, 3-year moving average, and 5-year most recent average) consistently. Rather, he appears to have usually selected the lowest number from these observations.

For instance, for account 355, the average is negative 65 percent, the three-year moving average shows an increasing trend up to negative 51 percent, and the 5-year average is negative 60 percent. Mr. Stout chose the average, negative 65 percent, for use in his study. But for Account 356, the average is negative 61 percent, the 3-year moving average shows an increasing trend up to negative 67 percent, and the 5-year average is negative 82 percent. In this case, Mr. Stout did not adopt the average value as he did for Account 355. Rather, he utilized the lowest number, rounded to negative 80 percent.

For account 356, Overhead Conductors and devices (HOU3-14), Mr. Stout uses a negative 80 % for net salvage, though the historic average was –61%, and the three year averages do not show an increasing trend. In fact, the recent historic numbers are high largely because of the years 1994 and 1995, in which the removal cost was higher than the amount of plant retired. Mr. Stout does not describe analyzing these data points. In RFI HOU 3-14, he indicates that his reason for increasing the net salvage percentage was that retirements in the past have occurred at ages less than his estimated average life, so that salvage costs will exhibit a higher proportion to retirement values. However, salvage itself should exhibit a higher proportion to retirement values. Salvage values are likely to be low for the last years of the data, as scrap metal prices were low. Since that time I have seen evidence that such prices have increased.

For Account 390, Structures and Improvements, the five-year average net salvage rate was 29%, yet Mr. Stout used a rate of 0%. His rationale is that the retirements that produced these results occurred at ages less than the 40 year retirement life that he is assuming. (HOU 3-16) He has not presented any analysis that demonstrates that a change in retirement age will produce such a significant change. Until 1995 the retirement amounts were minuscule (below $350,000, compared to the $1.9 million of retirements in 1998. There does not seem to be any analysis indicating why there was such a large change in retirement behavior, or what normal behavior in the future would be.

For account 364, poles, towers and fixtures, Mr. Stout uses the most recent 5 year average of 45% rather than the historic average of 31%, even though the recent trend of the 3 year averages seems to be downward.

Q. WHY AGAIN IS IT INAPPROPRIATE TO UTILIZE THE YEARS IN WHICH SALVAGE VALUES WERE UNUSUALLY LOW OR REMOVAL COSTS WERE EXTRAORDINARILY HIGH?

A. The inclusion of this anomalous data will not create an accurate projection of future salvage rates. The historic data is being utilized to predict future events. If the historic data contains events that are extraordinary and are unlikely to If in the future some extraordinary even occurs that decreases salvage, there are other means by which the Company can recover these expenses.

Q. IS THERE ANYTHING ELSE ABOUT THE SALVAGE STUDY THAT CONCERNS YOU?

A. Yes. There does not appear to be any recognition of any technological changes that might increase the life of transmission and distribution plant.

Q. WHY MIGHT THIS AFFECT THE DEPRECIATION STUDY?

A. I would expect that electrical engineers are continually attempting to design better equipment that will last longer with less maintenance. Moreover, environmental pressures should result in more equipment being recycled, which may increase salvage values. There is no recognition of these possibilities in Mr. Stout's study. There could actually be significant technological improvements that improve salvage value or reduce removal costs.

Q. CAN YOU PROVIDE EXAMPLES OF TECHNOLOGICAL CHANGES IN TRANSMISSION AND DISTRIBUTION PLANT?

A. Examples would include newer treatment of wood poles designed to increase their life, and substitution of concrete and steel poles for wooden ones. Transformers used to use PCBs, which made it expensive to remove and dispose of them due to the regulations regarding toxic waste disposal. Newer transformers do not contain PCBs, which will eliminate the associated cost of toxic waste disposal. While there appear to still be large numbers of PCB contaminated transformers in service, some newer transformers should be showing up in the retirement column soon.

Q. THE METHODS DESCRIBED WERE APPLIED TO MOST PLANT. WHAT PLANT WAS TREATED DIFFERENTLY, AND HOW?

A. Mr. Stout proposes that certain generation plant accounts, 391, 393, 394, 395, 397, and 398, be treated as if they have a fixed life, since these items are low cost. This method avoids the inventorying of this plant.

Q. WHAT DO YOU RECOMMEND FOR DEPRECIATION EXPENSE.

A. I recommend that the Commission utilize the previously approved depreciation rates in this case. The result is a decrease in most depreciation rates. I have calculated the depreciation expense resulting from these rates and from my recommended adjusted rate base in Exhibit LS-4.

Q. **IF YOU HAVE NOT ADDRESSED AN ISSUE, DOES THIS IMPLY THAT YOU ACCEPT THE COMPANY'S COST?**

A. No, it does not. The proposed increase in taxes other than income taxes appears inordinately large. Also, a number of costs should be decreased as a result of the recommendations that I have made. I have not calculated the reduction in income tax that will result from the lower rate base, or the reduction in working capital that will result from the reduction in expenses.

Q. **HAVE YOU SUMMARIZED YOUR REVENUE RECOMMENDATIONS?**

A. Exhibit LS-5 shows each of the discrete adjustments that I have made.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.